UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
GULF OF MEXICO REGION

ACCIDENT INVESTIGATION REPORT

1. OCCURRED
   DATE: **30-DEC-2009** TIME: **0900** HOURS

2. OPERATOR: **Murphy Exploration & Production Co**
   REPRESENTATIVE:
   TELEPHONE:
   CONTRACTOR: **Murphy Exploration & Production**
   REPRESENTATIVE:
   TELEPHONE:

3. OPERATOR/CONTRACTOR REPRESENTATIVE/SUPERVISOR ON SITE AT TIME OF INCIDENT:

4. LEASE: **G16645**
   AREA: **MC** LATITUDE: **28.275**
   BLOCK: **737** LONGITUDE: **-88.362**

5. PLATFORM:
   RIG NAME:

6. ACTIVITY:
   - [X] EXPLORATION(POE)
   - [ ] DEVELOPMENT/PRODUCTION (DOCD/POD)

7. TYPE:
   - [ ] HISTORIC INJURY
     - [ ] REQUIRED EVACUATION
     - [ ] LTA (1-3 days)
     - [ ] LTA (>3 days
     - [ ] RW/JT (1-3 days)
     - [ ] RW/JT (>3 days)
     - [ ] Other Injury
   - [ ] FATALITY
   - [X] POLLUTION
   - [ ] FIRE
   - [ ] EXPLOSION

   LWC
   - [ ] HISTORIC BLOWOUT
   - [ ] UNDERGROUND
   - [ ] SURFACE
   - [ ] DEVERTER
   - [ ] SURFACE EQUIPMENT FAILURE OR PROCEDURES

   COLLISION [ ] HISTORIC [ ] >$25K [ ] <=$25K

   - [ ] STRUCTURAL DAMAGE
   - [ ] CRANE
   - [ ] OTHER LIFTING DEVICE
   - [ ] DAMAGED/DISABLED SAFETY SYS.
   - [X] INCIDENT >$25K **$60550000.**
   - [ ] H2S/15MIN./20PPM
   - [ ] REQUIRED MUSTER
   - [ ] SHUTDOWN FROM GAS RELEASE
   - [X] OTHER **Leaking P&A'd Subsea Wellhead**

6. OPERATION:
   - [ ] PRODUCTION
   - [ ] DRILLING
   - [ ] WORKOVER
   - [ ] COMPLETION
   - [ ] HELICOPTER
   - [ ] MOTOR VESSEL
   - [ ] PIPELINE SEGMENT NO.
   - [X] OTHER **Spill Report from Overflight**

8. CAUSE:
   - [ ] EQUIPMENT FAILURE
   - [ ] HUMAN ERROR
   - [ ] EXTERNAL DAMAGE
   - [ ] SLIP/TRIP/FALL
   - [ ] WEATHER RELATED
   - [X] LEAK
   - [ ] UPSET H2O TREATING
   - [ ] OVERBOARD DRILLING FLUID
   - [X] OTHER **Subsea Wellhead**

9. WATER DEPTH: **6050** FT.

10. DISTANCE FROM SHORE: **73** MI.

11. WIND DIRECTION: **SE**
    SPEED: **11** M.P.H.

12. CURRENT DIRECTION: **E**
    SPEED: **1** M.P.H.

13. SEA STATE: **7** FT.

14. PICTURES TAKEN: **NO**

15. STATEMENT TAKEN: **NO**

17. INVESTIGATION FINDINGS:

The Incident

MC Block 737, Well 01 was spud during July 2006 in 6,108 feet of water and was sidetracked to a total depth of 22,814 feet of measured depth. The well was subsequently temporarily abandoned in November 2006. Murphy was required to permanently abandon the well by May 2008. Murphy completed permanent abandonment operations in June 2008 and kept the wellhead in place.

Although the sheen was first observed on 29 December 2009 at less than one barrel, Murphy notified the MMS New Orleans' District of a sheen in MC 736 located 2.1 miles away from Thunder Hawk platform on 30 December 2009. At time of the notification:
* Seas were 5-7 feet with winds from the southeast at 11 MPH.
* Sea current was approximately 0.6 knots to the east.
* Sheen was approximately ½-mile long by 2.2 miles wide

Murphy identified the possible the source of the leak on 31 December 2009 as MC 737 Well No. 01 ST 01. On 4 January 2010 Murphy confirmed the source with an ROV and continuously monitored the wellhead. No further flow from the wellhead was observed after 0200 hours on 10 January 2010. Murphy estimated that the well flowed approximately 5.1 barrels per day (62 cumulative barrels) throughout the duration of the release. This estimated volume is based on USCG Estimation Table and determined by the size of spill (length/width), percent of coverage, and appearance of coverage.

The pollution incident had no known coastal impact on the environment or wildlife.

Well Control Response

Initially, the Diamond Ocean Confidence (Ocean Confidence) was contracted by Murphy to perform kill operations on the leaking well, and the Ocean Confidence arrived at MC 737 on 2 January 2010. The response was delayed by 3 weeks due to a BOP stump test failure where flange bolts between the middle double U ram body and the upper double U ram body parted on the Ocean Confidence once it arrived on location. In response to this delay, the MMS and the USCG met daily with Murphy to identify all other rigs working within the vicinity to possibly assist in the response, especially those operated by Murphy's partners on the subject lease. The investigation team could not confirm any prearranged agreements Murphy had with other OCS operators or drilling contractors to assist in well control incidents.

The Transocean Clear Leader (Clear Leader) was released by Chevron to aid in the response, and the Clear Leader arrived on location on 17 January 2010. The Clear Leader experienced multiple BOP setbacks, such as ground fault problems, and was not able to successfully pull the wear bushing from the well until 30 January 2010. Once the wear bushing was pulled, the Clear Leader moved off location, and the Ocean Confidence latched onto the wellhead 32 days after the initial sheen observation and confirmed no flow.

Murphy had negotiated rig acquisitions with two other operators. One operator had concerns about losing their well, and the other operator was concerned about MMS's stance on lease term issues. At the time of the incident, there were 12 rigs working in the GOM that had the capability to work in the MC 736/737 area; however, attainment of a rig to respond raised questions regarding the options that Federal agencies have under the current regulations. The regulations at 30 CFR 250.300(a)(2) allow the Director of MMS to "control and remove" pollution; however, the MMS is unclear in how to exercise such authority and "order/direct" other operators and assets to respond to emergency situations.

Hydrocarbon Zones

The digital logging data on the subject well on record with the MMS begins at a depth of 15,534' MD and continues to a depth of 26,774' MD. Logs obtained by the investigation team were run in the original wellbore and sidetrack. The neutron porosity tool was run from 17,062'- 26,704' MD with breaks in the run from 19,011' - 19,072' and 20,460' - 20,527' MD. The bulk density depths are 17,062' - 26,713.5' with breaks from 19,019' - 19,082' and 20,469' - 20,527' MD. Gamma Ray and Resistivity logs were run throughout the well with minimal breaks in the run.

The MMS' Resource Evaluation standard for a "show" would be the appearance of hydrocarbon on a log up to a minimum of 15' true vertical thickness as defined in 30 CFR 250.116. An initial evaluation was completed on 28 May 2008 with analysis finding only one zone capable of producing quantities above the 15' TVD requirement. The depth interval of this pay zone is from 19,426' - 19,565' and 19,651' - 20,125' MD separated by shale breaks. Only one official "show" in the mudlog was reported at a depth interval of 19426' MD.

Murphy reports possible hydrocarbon sources of:

11,647' - 11,658' MD: Possible pay of 9-10 feet and not sure of fluid type.
15,677' - 15,688' MD: Possible pay of 8 feet and not sure of fluid type.
18,080' - 18,084' MD: Possible pay of 4 feet and not sure of fluid type.
19,426' - 19,565' MD: Oil pay calculated at ~70 feet with slight gas.
19,651' - 20,125' MD: Oil pay calculated at ~20 feet with slight gas.

To be able to evaluate a well using the Log Evaluation System Analysis software a minimum of gamma ray, resistivity, neutron porosity and bulk density curves need to exist over the same depth interval. Currently, a company is not required to run any logs in a wellbore but must submit any they choose to run within 30 days of TD to the MMS. MMS' evaluation confirmed these possible hydrocarbons by visual inspection of the gamma ray and resistivity logs. However, without a full suite of logs run over the first three intervals, confirmation of hydrocarbon presence in those three intervals is not possible.

Upon completion of the sidetrack in MC 736 Well No. 01 in 2006, Murphy decided to evaluate the well further as a candidate for a future sidetrack and therefore temporarily abandoned the well. Facing lease termination abandonment requirements, Murphy opted to permanently abandonment the well in 2008 after performing a geological re-valuation on the well.

MC 737 Drilling History - All depths within this section are measured depth.

A 16" liner was run and cemented at 13,719' on 19 August 2006 with no returns while cementing. Over 2,000 barrels of mud were lost to the formation during this process. The liner was pressure tested and drilled out. No bond or temperature logs were run to confirm top of cement.

Murphy experienced a gas influx while drilling ahead at 16,195' with equivalent circulating density very close (0.42 ppg) to the formation integrity test. There was a possible 8 foot hydrocarbon zone with a gas show seen on the logging-while-drilling logs at 15,677-15,688'. To control the gas influx, Murphy weighted up their mud, but they started losing returns at 16,235'. To control the lost circulation zone, lost circulation material and then cement were pumped in. Murphy obtained verbal approval from the New Orleans district to bypass the lost circulation zone and set a 16" expandable liner at 15,680'. The investigation team was not able to identify any indication as to why the decision was made by Murphy to set this liner with the seat in the previously mentioned possible hydrocarbon zone. The top of the cement plug was encountered at 13,535' inside previous casing. While drilling cement back to the planned liner seat, lost circulation began around 14,850' and continued until drilling stopped at 15,680'. A total of over 2,000 barrels of mud were lost to the formations. The expandable liner was run, but it stuck off bottom at 15,469'. Murphy was unable to circulate or move the liner, and the liner was expanded in place with no cement. The liner was pressure tested and drilled out. A formation integrity test was run, and the planned bypass was kicked off at 15,534'.

Following the bypass, Murphy drilled to 17,100' and ran 13 5/8" by 13-3/8" tapered casing to 17,060', and they lost over 600 barrels of mud while running casing. Murphy then cemented the casing with no returns and lost an additional 1,800 barrels of mud. The casing was tested, drilled out, and a formation integrity test was run. There were no cement bond or temperature logs run to confirm top of cement.

Murphy drilled to 19085', and they ran open hole logs. Following the logs, Murphy ran and cemented 11-7/8" liner at 19,095' with no returns while cementing. Over 900 barrels of mud were lost to the formations. The liner was tested, drilled out, and a formation integrity test was run. There were no cement bond or temperature logs run to confirm top of cement.

Continuing downhole, Murphy drilled to 20,539' and ran open hole logs, downhole pressure tests, and sidewall cores. They also ran and cemented expandable liner with full returns. The liner was tested, drilled out, and a formation integrity test was run. There were no cement bond or temperature logs run to confirm top of cement.

No additional casing was set in this well and the remainder of the drilling was conducted with no unusual conditions or events. The well was temporarily abandoned on 28 November 2006.

MC 737 Well 01 ST01 Abandonment History

Murphy completed temporary abandonment operations in November 2006 in order to evaluate the well for potential future utility. Without future utility the lease would terminate in May of 2007, with MMS requirements mandating that all wells being plugged and abandoned by May 2008. Murphy completed permanent abandonment operations on June 2008 and kept the wellhead in place. During both (2006 TA and 2008 PA) abandonment operations, Murphy utilized two methods: the balanced plug method and the squeeze packer/retainer method.

Balanced Plug Method

The well's balanced plug method involved pumping cement slurry through the drill pipe until the level of cement inside the drill pipe was equal to that in the casing annulus. The drill pipe was then slowly pulled from the slurry, leaving the slurry to cure. To minimize cement contamination by wellbore fluids, fluid spacers were used both ahead of and behind the slurry; especially since the well's drilling mud is incompatible with the cement slurry. The balanced plug method was used during the 2006 T&A for the bottom plug's top set at 20,354' above the retainer (acting as a mechanical plug) at 20,454', the second to last 200-foot plug located at 16,610', and the top 100-foot plug set 6,286'.

Squeeze Packer/Retainer Method

A squeeze packer that also acted as a retainer was used. The packer utilized an operating mandrel (stinger) inserted into the packer bore to seal the drill pipe and squeeze cement through the perforations located below the packer. The squeeze packer/retainer method was used during the 2008 P&A. The packer/retainer was set at 7,483' and cement was squeezed through the lower perforations at 7,492'-7496', up the 13-5/8" x 22" annulus and through the top perforations at 7,200'-7,210'.

Title 30 CFR Part 250 Section 250.1715 was used to determine that Murphy complied with the cement plug requirements for plugging this well. Actual cement and displacement volumes with pressure testing results were utilized from the IADC report to calculate that the cement plugs were of sufficient length and set at the estimated depths.

MMS Cement Plug Testing Requirements

In accordance with the MMS regulations, Murphy has the option to use one of the

following tests to verify the integrity of the surface plug, all plugs in lost circulation areas that are in open hole, and those additionally required by the District Supervisor:
* A pipe weight of at least 15,000 pounds on the plug; or
* A pump pressure of at least 1,000 pounds per square inch. Ensure that the pressure does not drop more than 10 percent in 15 minutes.

Murphy utilized only pressure tests for abandonment testing of all plugs except the plug at 16,610'. The 16,610' plug was not required by MMS regulations to be tested and no plug testing was ordered by MMS.

Abandonment Cementing Operational Problems

The only problems that occurred during the 2008 P&A was on 5 June 2008 when the 13-5/8" packer and perforating gun assembly left at 6390' (during the 2006 T&A) could not be milled out and was pushed down the well to 7800'. [Note: This same assembly required 14 days of milling to be removed from the well during the 2010 re-entry.] In addition, on 7 June 2008 several unsuccessful attempts were made to set a 13-5/8" cement retainer at 6496', 6494', 6489' and 6484' when the retainer's setting slips did not protrude far enough to hold the retainer. The slips were replaced and the retainer set at 6496' to perform the P&A top plug at 6296' on 8 June 2008. No other problems could be attributed to the actual cementing operations.

Well Reentry Operations

Over the course of the wellbore re-entry, Murphy collected mud samples at various depth intervals. As the depths got greater, lab testing on the mud indicated an increasing trend of crude oil contamination. According to Murphy representatives working on the incident, the flow was coming from beneath the 16,610 plug, and it was coming from the center of well. Due to these measurements inside the well, Murphy did not expect the source of the flow was occurring in the annulus. Gas shows had ranged from 0 to 5,000 units during the re-entry and oil shows had increased with depth which indicated the plug at 16,610' failed.

On 5 March 2010 Murphy encountered Asphaltene returns from below 11,213' which required Murphy to shut-down operations and request approval to abandon the well at this depth. The presence of the Asphaltene could have possibly plugged the choke line. Although the kill line is available if the choke line became plugged, Murphy would not have circulated the oily shale debris up the kill line in order to keep the kill line available for well control. The second concern was packing off and sticking the 12-1/4" Milling BHA in the hole.

MMS Approval for Final Abandonment

Within their re-abandonment request, Murphy was approved to permanently abandon the well at 11,000' on top of Asphaltene debris at 11,050'. Within the procedure, Murphy set a 1000' foot cement plug at 11,000' on top of a cast iron bridge plug (CIBP), set a 500' cement plug on top of a CIBP at 9,000', cut the 13-5/8" casing, set a cement plug at 7,650', and set an inflatable bridge plug at 6,700' with an additional 400' cement plug above it. All approved plugs were required to: 1) be weight tested by tagging and setting down on the plug, 2) pressure tested to 1,000 psi, and 3) have a negative test on the plug for 15 minutes. Murphy completed final abandonment of the well on April 4th.

18. LIST THE PROBABLE CAUSE(S) OF ACCIDENT:

The Incident

It is concluded by the investigation team that on 29 December 2009 a pollution incident occurred as result of a leak associated with the MC 737 permanently abandoned Well No. 001 ST01. This leak allowed for the release of approximately 62 barrels to the Gulf of Mexico.

Cause

Due to Murphy's inability to get below 11,213' after reentering the well in an attempt to identify the source and path of the pollution, the investigative team cannot identify the specific cause of the incident. (For schematic of possible flow scenarios, see Attachments 7-10.)

Possible Source and Flow Path

During the 2010 re-entry operation, the squeezed perforations and top two cement plugs held positive pressure prior to being drilled out. The cement plugs at 16,610' and 20,354' were unable to be reached during the re-entry operation. The fact that all other cement plugs encountered were near their estimated top of cement depths, and of sufficient length based on slurry calculations/displacement calculations, can be attributed to the following:

*** The bulk cement materials received by the rig exhibited their expected properties.**
*** Mixing of the all cement materials was done properly.**
*** The estimated cement and displacement volume calculations were accurate.**
*** The cement pumping operation was conducted as to prevent cement slurry contamination during the cement curing period.**
*** Estimated wellbore pressure and temperature conditions used to design the cement slurries were accurate.**

Murphy utilized only pressure tests for abandonment testing of all plugs requiring testing. The 16610' plug was not required by MMS regulations to be tested and no plug testing (pressure and/or pipe weight) was ordered by MMS. Based on the fact that asphaltenes were discovered 200' above this plug would indicate possible failure of this plug. Plug testing might have identified the need to reset said plug during the initial well 2006 T&A.

There are cases in industry where a cement plug will sustain pressure from top down, but when an attempt to tag the plug was made, the plug had moved down the wellbore. In addition, successfully pressure testing a plug from top down doesn't necessarily indicate that the plug will hold negative pressure; pressure from below the plug. This becomes critical should the well fluid above the plug be displaced later with a lighter fluid; thereby, resulting in a negative test of the plug. In November 2006 during the T&A, only the cement plug at 6286' was negatively tested subsequent to displacing the mud from above the plug with seawater. This plug, however, was set on top of a retainer with the retainer being positively tested to 1000 psi.

The inability to reach the last two cement plugs in the well leaves uncertainty to whether possibly the 16610' plug failed or possibly both this plug and the 20354¿ plug failed. Wellbore schematics demonstrate that flow could have reached the surface past the 16610' plug without failure of the 20354' plug from flow through the stratified hydrocarbon zone at 19426'-20125' and failure of the liner top at 16950'. Flow was also possible through both the 16610' and 20354' plugs from the open hole below the 20354' plug.

Actual cement and displacement volumes with pressure testing results were utilized from the IADC reports to calculate that the estimated cement plugs were of sufficient length, set at the estimated depths, and pressure tested successfully in accordance with 30 CFR 250.1715. However, the investigation team could not confirm the lowest two

plugs top of cement since Murphy was not able to reach said plugs after re-entering the well.

In summary, although the squeezed perforations and top cement plugs were successfully positively (top down) pressure tested prior to being drilled out during the 2010 re-entry operation, there remains the possibility that these squeezed annulus and top plugs might not have been able to hold a negative (bottom-up) test pressure later in the life of the well. The inability to reach the 16610' plug, resulting from the asphaltene problem, would indicate that at minimum the 16610' plug failed. Failure of the 16610' plug could have then created the "negative test" (bottom-up) pressure situation on the upper plugs. However, the fact that these top plugs were encountered near their estimated top of cement depths, were of sufficient length based on slurry calculations/displacement calculations, and all held positive pressure during the 2010 re-entry, greatly reduces the possibility of surface plug failure.

Therefore, the four possible flows sources below the 16,610' plug may have come from: (1) the possible pay hydrocarbon zone from 18,080'- 18,084', (2) the stratified hydrocarbon zone at 19426'- 20125', (3) the liner top at 16850' or (4) open hole below the 20,354' plug.

19. LIST THE CONTRIBUTING CAUSE(S) OF ACCIDENT:

Procedures

Since the operator did not perform bond or temperatures, it is concluded by this investigation that the failure to perform such logs was a possible contributing cause in this incident.

The investigation team identifies multiple cement jobs being completed without assurance of the cement displacement within this well to be possible contributing causes to the release of hydrocarbons into the environment.

The investigation team concludes that the Murphy‡s decision to not perform logs throughout the well to identify all potential hydrocarbon zones is a possible contributing cause in this incident.

It is concluded by this investigation that the performance of the Squeeze Packer/Retainer method was a possible contributing cause in this incident since the 13-5/8" x 22" annulus was not negatively tested.

Regulations

The lack of well logging and bond or temperature log requirements was a possible contributing cause in this incident.

20. LIST THE ADDITIONAL INFORMATION:

21. PROPERTY DAMAGED: NATURE OF DAMAGE:

N/A **N/A**

ESTIMATED AMOUNT (TOTAL): **$60,550,000**

22. RECOMMENDATIONS TO PREVENT RECURRANCE NARRATIVE:

Research

The investigation team recommends that the MMS should consider the following research projects which are presented in order of significance.

1. Determine existence of leakage of plugged and abandoned subsea wells with focus on older abandonments.
2. Determine the validity of pressure testing, weight testing, or negative testing cement plugs in various configurations within the wellbore.
3. Evaluate if the annuli of subsea wells need to remain open to the formations below the shoe if the well is used for production.
4. Study available bond logging technology and possible regulatory change.
5. Examine placement techniques to include (1) mud conditioning, (2) use of spacers, (3) pipe movement, (4) the use of scratchers/centralizers and (5) sufficient cement slurry volume required to minimize or eliminate contamination.
6. Verify the ability of additives, designer cements, polymers and epoxies to resist de-bonding from the casing and cracking under static and cyclical loading.
7. Evaluate the performance of new cement systems with special properties like foam and expansive cements.
8. Review the performance of polymer/epoxy and cement blends in high-pressure/high-temperature well abandonment situations.

Regulation Change

Dependent upon the findings in the research proposed above (item number 2), the MMS should modify 30 CFR 250.1715 to require testing of all cement plugs with both pipe weight and pressure tests.

The MMS should clarify our jurisdiction under 250.300(a)(2) and define when such authority is applicable and how such authority will be exercised.

The MMS should consider revising 30 CFR 250.1716(b)(3)'s water depth requirements for the removal of a wellhead and casings.

The MMS should consider the revision of 30 CFR Subpart A to include requirements on minimal logging requirements on OCS wells.

The MMS should modify 30 CFR Subpart A to define hydrocarbon show, zone, interval, etc.

23. POSSIBLE OCS VIOLATIONS RELATED TO ACCIDENT: **NO**

24. SPECIFY VIOLATIONS DIRECTLY OR INDIRECTLY CONTRIBUTING. NARRATIVE:

25. DATE OF ONSITE INVESTIGATION:

30-DEC-2009

26. ONSITE TEAM MEMBERS:

28. ACCIDENT CLASSIFICATION:

MINOR

29. ACCIDENT INVESTIGATION PANEL FORMED: **NO**

Larry Williamson / Rebecca Dufrene / Ben Coco / Glynn Breaux / Jason Mathews /

OCS REPORT:

30. DISTRICT SUPERVISOR:

Glynn T. Breaux

27. OPERATOR REPORT ON FILE: **NO**

APPROVED DATE: **30-JAN-2012**

POLLUTION ATTACHMENT

1. VOLUME: GAL **62** BBL

   YARDS LONG X YARDS WIDE

   APPEARANCE: **RAINBOW SHEEN**

2. TYPE OF HYDROCARBON RELEASED:
   - [x] OIL
   - [ ] DIESEL
   - [ ] CONDENSATE
   - [ ] HYDRAULIC
   - [ ] NATURAL GAS
   - [ ] OTHER ____________________

3. SOURCE OF HYDROCARBON RELEASED: **subsea wellhead leak**

4. WERE SAMPLES TAKEN? **NO**

5. WAS CLEANUP EQUIPMENT ACTIVATED? **NO**

   IF SO, TYPE:
   - [ ] SKIMMER
   - [ ] CONTAINMENT BOOM
   - [ ] ABSORPTION EQUIPMENT
   - [ ] DISPERSANTS
   - [ ] OTHER ____________________

6. ESTIMATED RECOVERY: GAL BBL

7. RESPONSE TIME: HOURS

8. IS THE POLLUTION IN THE PROXIMITY OF AN ENVIRONMENTALLY SENSITIVE AREA (CLASS I)? **NO**

9. HAS REGION OIL SPILL TASK FORCE BEEN NOTIFIED? **NO**

10. CONTACTED SHORE: **NO** IF YES, WHERE:

11. WERE ANY LIVE ANIMALS OBSERVED NEAR: **NO**

12. WERE ANY OILED OR DEAD ANIMALS OBSERVED NEAR SPILL: **NO**